For events defined by NERC as Category C events, ensuring compliance with national ERO reliability standards requires under the NERC TPL standards, the following[3]:

> "The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard."

Category C3 events are defined in the TPL standard as events resulting in the loss of two or more (multiple) elements, and more specifically as a:

> SLG or 3Ø Fault (on a generator, transmission circuit, or transformer), with Normal Clearing, Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing.
>
> Table I of this standard further describes the permissible system performance for these C3 events as requiring:
>
> - System Stable and both Thermal and Voltage Limits within Applicable Rating
> - No Cascading Outages
> - Planned/controlled Loss of Demand or Curtailed Firm Transfers is permitted. (This performance requirement is footnoted as saying that "Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems."

[3] NERC Standard TPL-003-0 Requirement R1.

The combined result of these requirements under the tariff, and under the NERC TPL standards, is that for Category C3 events such as the sequential (non-simultaneous) loss of a generator and a line or transformer, the loss of two (2) lines or two (2) transformers, or of a line and a transformer, compliance with the standard permits the controlled shedding of load, tripping of generators, or redispatch of resources resulting in the curtailment of firm transfers, if required in order to prevent instability or cascading outages.

The following business practices are not intended to define planning criteria, to judge the appropriateness of any transmission system expansion proposed for implementation as a means to address system performance requirements for NERC Category C3 events, or to establish new tariff eligibility requirements for cost sharing of Baseline Reliability Projects. Rather, these practices define the decisions to be made by MISO planning staff in determining which reliability projects will be considered by MISO to meet the tariff defined characteristics of a Baseline Reliability Project of being "required to ensure that the Transmission System is in compliance with" the performance requirements for NERC Category C3 events.

J.5.1.1: System Reconfiguration and Redispatch Evaluation for Category C3 Events

System reconfiguration will be considered as an acceptable system adjustment following loss of the first element of a Category C3 Event, and prior to the loss of the second element, in order to maintain system loadings and voltages within applicable ratings following the second event. System reconfiguration includes supervisory controlled or automatic operation of bus-tie circuit breakers, switching of transmission lines, transformers, series or shunt reactive devices, or adjustment of controllable elements such as LTC transformers, phase angle regulators, HVDV lines, generator voltage regulators or other such devices. System reconfiguration must be such as to maintain system loadings and voltages within applicable ratings for any subsequent facility outage in addition to the originally contemplated C3 event.

Redispatch will also be considered as an acceptable system adjustment to be made following the outage of the first element of a Category C3 Event, and prior to the outage of the second element. It is assumed, unless demonstrated to the contrary, that the expected value of cost of such a reliable-redispatch following the outage of the first element would be very low and would always provide an economically superior solution to a comparable Network Upgrade. This is because of the very low probabilities of being in the post single contingency outage state coupled with the system load and dispatch conditions resulting in reliability violations anticipated for the second outage. To ensure that the generation redispatch is an economically superior solution when compared with a network upgrade, the study must demonstrate that the redispatch is a reliable alternative to mitigate the NERC-C3 contingent constraint. The following criteria have been developed to better define a "reliable" redispatch.

1. Due to the uncertainty that any existing generating unit will continue to be a viable unit over the planning horizon, redispatch evaluation must demonstrate that there are sufficient generating units that are available to provide the incremental capacity necessary to maintain loadings and voltages within applicable ratings, without reliance on any single unit. In general, all Network Resources (NR's) and Energy Resources (ER's) are candidates for redispatch as their output can be reduced to minimum levels or turned off, including wind plants. If generating units are to be decommited, the reliability impacts of the generation change, including a voltage analysis, would need to be evaluated. The participating generators must have a distribution factor of greater than 3%. Distribution factor is defined as the sensitivity of the generating unit to the thermal constraint resulting from the C3 contingent event. Lower than 3% distribution factor is indicative of an inefficient redispatch.
2. No more than 10 units shall be used in any redispatch scenario.
3. No more than 1000 MW shall be used to increment and no more than 1000 MW shall be used to decrement in any redispatch scenario. Therefore, no more than a total amount of 2000 MW of generation shift shall be allowed to redispatch around a constraint.
4. Non dispatchable units will be excluded from redispatch calculations. Nuclear generating units will also be excluded unless otherwise required by their operating agreements. In general, feedback from Stakeholders will be requested regarding the reasonableness of units to be considered in the redispatch options prior to commencement of the annual MTEP reliability assessments.
5. After redispatch the loadings on all facilities should be within applicable ratings per the Transmission Owner facility rating methodology consistent with NERC FAC-008 standard.

6. Consideration of external generation in redispatch calculations:
    a. If the identified C3 driven constraint is a PJM-MISO reciprocal coordinated flowgate (RCF) eligible for market to market redispatch, PJM units will be included in the redispatch.
    b. If the identified C3 driven constraint is not currently a PJM-MISO reciprocal coordinated flowgate (RCF), the flowgate would be recommended for RCF qualification study. If not eligible, PJM units will not be included in the redispatch.
    c. Generators considered within existing operating guides, procedures and Special Protection Schemes (SPS) will be included as applicable to the overloaded facilities.
    d. No other non-MISO units along seams will be used in redispatch.

To the extent that such reliable-redispatch is shown to be available using the applicable MISO MTEP planning model to maintain system loadings and voltages within applicable ratings following the second outage, of a Category C3 event, MISO business practice will be to not accept a Network Upgrade proposed as a Baseline Reliability Project eligible for cost sharing.

J.5.1.2: Load Shedding Limits after which Baseline Reliability Projects are Supported for Cost Sharing

Because the NERC TPL standards do not state a limit as to the amount of load shedding that is permissible in order to maintain system stability and to avoid cascading outages following a Category C3 event, MISO business practice will be to accept as a Baseline Reliability Project eligible for cost sharing (subject to passing the project cost and voltage thresholds of Attachment FF), a Network Upgrade that is needed to avoid any of the following, after the redispatch and reconfiguration options of Section I.5.1.1 have been exhausted:

1. Controlled Load shedding of 100 MW or more implemented as an operating guide prior to the second element outage and as demonstrated to be necessary using the applicable MISO MTEP planning model, to avoid instability or an unbounded cascading following the second element outage.
2. Bounded thermal cascading outages resulting in 300 MW or more of load as a consequence of sequential element trips, as demonstrated to occur using the applicable MISO MTEP planning model, and the thermal cascading outage testing method of Section 4.3.7 A. of this BPM.

3. Loss of electric service to more than 50,000 customers as estimated by the Transmission Owner with agreement from the affected Local Distribution Company, and as a consequence of sequential element trips, as demonstrated to occur using the applicable MISO MTEP planning model, and the thermal cascading outage testing method of Section 4.3.7 A. of this BPM.

Condition 1, above has a lower load loss amount than condition 2, because condition 1 would shed this load after a single contingency in anticipation that the second contingency would result in an unbounded cascading event. Condition 2 would result in the larger amount of lost load only in the event that the second contingency actually occurred, and therefore would occur with much less frequency.

Condition 3 reflects that in lower average customer peak demand areas, 50,000 customers may represent less than 300 MW of load, but would represent a similarly severe customer outage event.

The above conditions are based on the threshold reporting requirements established for emergency events by the Department of Energy (DOE) and reportable on form OE-417. See http://www.oe.netl.doe.gov/oe417.aspx

According to the DOE OE-417 establishes mandatory reporting requirements for electric emergency incidents and disturbances in the United States. DOE collects this information from the electric power industry on Form OE-417 to meet its overall national security and Federal Emergency Management Agency's National Response Framework responsibilities. DOE will use the data from this form to obtain current information regarding emergency situations on U.S. electric energy supply systems. DOE's Energy Information Administration (EIA) will use the data for reporting on electric power emergency incidents and disturbances in monthly EIA reports. The data also may be used to develop legislative recommendations, reports to the Congress and as a basis for DOE investigations following severe, prolonged, or repeated electric power reliability problems.

Appendix K: Notes to Disturbance-Performance

Notes:

1. *The MAPP Disturbance-Performance Table applies to the initial transient period following the contingency (up to 20 seconds) and the post-disturbance period (20 seconds to 30 minutes);*
2. *The following summarizes the automatic and manual readjustments that are permissible for all NERC category B disturbances.*
   - A. *Generation Adjustments (Spinning and Non-Spinning Operating Reserve) – Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation changes is limited to that amount that can be accomplished within the Readjustment period. Due consideration will be given to start up time and ramp rates of the units.*
   - B. *Capacitor and reactor switching – The number of capacitors and reactors, which may be switched, is limited to those which could be switched during readjustment period.*
   - C. *This includes those capacitors and reactors that would be switched by automatic control with the same period.*
   - D. *Adjustment of Load Tap Changers (LTC's) to the extent possible within the Readjustment period. This includes both LTC's which would automatically adjust and those under operator control which could be adjusted within the Readjustment period.*
   - E. *Adjustment of phase shifters to the extent possible within the readjustment period. Agreement must be obtained from the owner(s).*
   - F. *Adjustment of the amount of the flow the HVDC can be increased or decreased within the readjustment period.*
   - G. *Generation Rejection – Generation may be rejected in one of two methods; tripping the generating unit or tripping generation supported tie lines. For either method, the amount of effective generation rejection within the Readjustment period will not exceed 80% of the normal operating spinning reserve of the MAPP system (one half of 1.5 times the largest unit). The following limits apply to generation rejection when tripping generating units:*
     - *Hydro – up to one plant*
     - *Fossil – Up to two units at a plant*

H. Transmission Reconfiguration – Automatic and operator initiated tripping of transmission lines or transformers within the readjustment period.

I. Non-firm load shed – Automatic or manual tripping of interruptible load being supplied under MAPP service schedule L or the pre-determined re-dispatching of Non-Firm Point-to-Point Transmission service within the readjustment period.

3. *The following additional readjustments may be considered for all NERC Category C contingencies.*
   - *A. Generation rejection – One nuclear unit may be rejected as long as the loss is less than 80% of the normal operating spinning reserve of the MAPP System (one half of 1.5 times the largest unit).*
   - *B. Firm load shed – Automatic or manual tripping of firm Network or Native Load or the predetermined re-dispatching of firm Point-to-Point Transmission Service and Firm Transmission Network Service.*
4. *The following additional readjustments may be considered for all NERC Category D contingencies.*
   - *A. It is assumed that some planned and controlled islanding will occur for the most credible extreme disturbances. Automatic under-frequency load shedding as specified in Standard III.D is expected to arrest declining frequency and generation rejection is expected to arrest increasing frequency in order to assure continued operation within the resulting islands.*
   - *B. Automatic under-voltage load shedding as specified in Standard III.E is permissible to arrest declining voltages and prevent widespread voltage collapse.*
5. *The criteria listed in the MAPP Disturbance-Performance Table are the default limits. Specific buses, control areas or companies may have more or less restrictive criteria. Refer to the current MAPP members' reliability criteria and study procedures manual for a complete listing of specific reliability criteria.*
6. *Additional voltage requirements associated with voltage stability are specified in Standard I.D. If it can be demonstrated that post transient voltage deviations that are less than the values in the MAPP disturbance-performance table will result in voltage instability, the system in which the disturbance originated and the affected system(s) should cooperated in mutually resolving the problem.*

7. *Apparent impedance transient swings into the inner tow zones of distance relay are unacceptable for NERC/MAPP category B and C1, C3, C4 and C5 disturbances, unless documentation is provided showing the actual relays will not trip for the event. Apparent impedance transient swings into the inner two zones of distance relays are unacceptable for NERC/MAPP category C2, C6, C7, C8 and C9 disturbances, unless documentation is provided that demonstrates that a relay trip will not result in instability (including voltage instability), uncontrolled separation, or cascading outages.*
8. *A one-cycle safety margin must be added to the actual or planned fault clearing time.*
9. *The machine rotor angle damping ratio is determined by modal analysis (e.g. Prony analysis or equivalent). Alternatively, the Rotor Angle Oscillation Damping Factor or Successive Positive Peak Ratio (SPPR) can be calculated directly from the rotor angle, where the rotor angle response allows such direct calculation. For a disturbance with a fault, the SPPR must be less than 0.95 or the damping factor must be greater than 5%. For a disturbance without a fault, the SPPR must be less than 0.9 or the damping factor must be greater than 10%. Refer to the current MAPP members reliability criteria and study procedures manual for a description of the calculation methodology.*
10. *The parameters listed the MAPP disturbance-performance table are the default minimum limits on MAPP's Canada-U.S. interface. Refer to the MAPP members reliability criteria and study procedure manual for a complete listing of specific reliability criteria, detailed descriptions and margin definitions.*

Appendix L: SOL (IROL) Methodology for the Planning Horizon Definitions:

System Operating Limit (SOL)—The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

Interconnected Reliability Operating Limit[1] (IROL)—A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.

Interconnected Reliability Operating Limit Tv[1] (IROL Tv)—The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's Tv shall be less than or equal to 30 minutes.

1 NERC Glossary of Terms Used in Reliability Standards, revised May 2, 2007
ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May07.pdf

Normal Rating[2] – The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or MVar or other appropriate units, that a system, facility, or element can support, produce, or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating[1] – the rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or MVar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Operating Horizon – The period from the current hour to and including the last hour of the twelfth month into the future. (Months 1-12 from current).

Planning Horizon – The period from the first hour of the thirteenth month into the future from the current hour to the last hour or the tenth year beyond the current year. (Years 1-10 from current, not including the current year).

R1 SOL Methodology:

The MISO establishes SOLs and IROLs for both the Operating and the Planning Horizons. The provided SOLs (including the subset of SOLs that are IROLs) shall include the identification of the subset of multiple contingencies (if any) from Reliability Standard TPL-003 which result in stability limits. The SOL/IROL Limits attained from Steady State, Voltage Stability, and Transient Stability analyses for the MTEP planning horizon is posted to two secure locations: The MISO Extranet Reliability Authority page and the MISO ftp site.

Instructions for access for the Extranet Reliability Authority are found at: http://extranet.midwestiso.org/How%20To%20Activate%20RA%20Information%20Access.pdf

Instructions for access for the MTEP ftp site are found at: https://www.misoenergy.org/Library/Repository/Study/MTEP/FTP%20Site%20Access%20Request%20Form.pdf

The methodology for developing SOLs and IROLs for the Planning Horizon are described in this document.

R1.1 Applicability of SOLs for the Planning Horizon:

SOLs and IROLs for the Operating Horizon are generally associated with determination of maximum power transfer limits across defined interfaces to which the system must be limited in real-time operations in order to ensure reliable and secure system operations, respectively. These transfer limits are often translated into specific flow limits on individual facilities or a group of facilities that define the interface for which the limit is established, in order that operating personnel may recognize the approach of such transfer limits and take necessary action to maintain reliable and secure operations. Such maximum transfer defined operating limits are most valuable in the Operating Horizon of up to 12 months into the future. Maximum transfer limits projected for future planning horizons of 1 year and beyond are of little value to operators in real-time operation of the system since the future system conditions for which they are established are likely to be of little relevance to the actual conditions in the operating horizon that the operator must be prepared for.

[2] NERC Glossary of Terms Used in Reliability Standards, revised May 2, 2007 ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May07.pdf.

In the Planning Horizon, SOLs and IROLs are not developed in terms of maximum transfer limits, but instead are established for specified system configurations or defined system conditions (system or area demand level and facility contingency conditions) consistent with NERC reliability Standards TPL 001, 002, 003, and 004. The SOL for the planning horizon is characterized by the system condition in terms of load level, the contingent facility outage conditions, and the thermal or voltage limit of the most limiting facility for the configuration.

R1.2 Relationship of SOLs and Facility Ratings:

Consistent with the applicability in section 3.1 above, SOLs in the planning horizon are described as the most limiting facility rating and its design thermal or voltage rating together with the system conditions at which the limit is reached or (without planned upgrades or other remedy) exceeded when applying the TPL standards. The SOL condition shall not produce any facility loading or voltage condition that exceeds the most limiting element that determines the Facility Rating.

R1.3 Relationship of SOLs and IROLs:

By definition, IROLs are a subset of SOLs that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System. Therefore, IROLs in the planning horizon are described as the system condition(s) (system or area demand level and facility contingency conditions) consistent with the NERC TPL standards for which (without planned upgrades or other remedy) instability, uncontrolled separation, or Cascading Outages are projected to occur.

R2 Determination of SOL Conditions in the Planning Horizon:

Short-term planning addresses identification of needs and solutions in the time frame of 1 to 10 years, with particular focus on the next 5 years. Screening reliability analyses are performed in the 6-10 year period to identify possible issues that may require longer lead-time solutions, as required by the NERC standards.

Baseline reliability analysis provides an independent assessment of the reliability of the currently planned MISO Transmission System for the short-term planning horizon (e.g., within the next five years). This is accomplished through a series of evaluations of the short-term system with Planned (committed) and Proposed transmission system upgrades, as identified in the expansion planning process, to ensure that they are sufficient and necessary to meet NERC and regional planning standards for reliability. This assessment is accomplished through steady-state power flow, dynamic, small-signal, load deliverability, and voltage-stability analysis of the transmission system performed by MISO staff and reviewed in an open Stakeholder process.

Regional contingency files are developed by MISO Staff collaboratively with Transmission Owner and Regional Study Group input. The list of contingencies will include events described under NERC TPL-001-0 through TPL-004-0, or any applicable local or RRO planning criteria or guidelines. Below is a list of typical contingency categories tested. The extent that SOLs affect BES performance is determined using the following contingency criteria:

R2.1 Pre Contingency State:

The transmission system is modeled under NERC Category A conditions (e.g. system intact) using both steady-state and dynamic stability analysis. Potential planning criteria violations (thermal overloads and low or high voltage conditions) are identified using Transmission Owner's design criteria limits. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to the system topology such as Facility outages.

R2.2 Post Contingency State:

The transmission system is modeled under NERC Category B and C Conditions (e.g., loss of single or multiple Bulk Electric System elements, respectively) using both steady-state and dynamic stability analysis. Planning criteria violations (thermal overloads and low or high voltage conditions) are identified using Transmission Owner's design criteria limits. Following the single Contingencies—(R2.2.1) Single line to ground or three-phase fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device or (R2.2.2) the loss of any generator, line, transformer, or shunt device without a Fault or a (R2.2.3) Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system—the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

R2.3 Single Contingency System Response:

For the short-term planning horizon, any potential criteria violations under NERC Category B conditions are thoroughly analyzed. This analysis identifies possible corrective measures to prevent or mitigate potential violations, including construction of new transmission facilities, power flow switching strategies, generator re-dispatch, or controlled interruption to local network customers within the Faulted Facility affected area. The planning process also determines that appropriate preventative or mitigation measures can be put in place before the end of the planning horizon.

R2.4, R2.5, R2.5.1 Multiple Contingency System Response:

For the short-term planning horizon, modeled criteria violations under NERC

Category C conditions are evaluated for their potential to result in Cascading Outages or uncontrolled separation This analysis identifies possible corrective measures to prevent or mitigate Cascading Outages or uncontrolled separation, including construction of new transmission facilities, power flow switching strategies, generator re-dispatch, or controlled load interruption or curtailment of firm transfers. The planning process also determines that appropriate preventative or mitigation measures can be put in place before the end of the planning horizon.

R3 Baseline Models:

The MISO Baseline Reliability study models will typically include power-flow models reflective of five-year out and ten-year out system conditions. Other variations of these may also be used as appropriate based on the stakeholder input for a given planning cycle. The MISO SOL methodology consists of each of the following elements:

R3.1 Topology:

The system topology in the Baseline Reliability Plan models will reflect the expected system condition for the planning horizon. This will include documented future transmission projects within the MISO Transmission System. The Baseline Reliability Plan models shall include at least the entire MISO's Planning Authority area as well as any critical modeling details from other Planning Authority areas deemed necessary to impact the Facility or Facilities under study. Following general criteria will be used to model future transmission projects:

- Planned projects with Expected In Service Date before the MTEP study horizon year (before July 1 for summer peak cases);
- Projects with Regulatory Approvals;
- Projects with system needs documented by a MISO study (i.e., a previous MTEP study, a Generator Interconnection study, a Transmission Service study, or a Coordinated Seasonal Assessment);
- Planned projects based on Conditionally Confirmed TSR upgrades;
- Upgrades related to Generator Interconnection requests with signed Interconnection Agreements;
- Projects which are not subject to cost sharing.

Future transmission upgrades are removed from the model if they have Withdrawn Planning Status, or if they do not meet the inclusion criteria above. The non-MISO system representation will be based on the latest external system for the planning horizon.

R3.2 Contingencies:

Regional contingency files are developed by MISO Staff collaboratively with Transmission Owner and Regional Study Group input. The list of contingencies will include events described under NERC TPL 001 through TPL004, or any applicable local or Regional Entity planning criteria or guidelines. Below is a list of typical contingency categories tested.

- NERC Category A is system intact or no contingency event.
- NERC Category B1-B4 faulted events for systems under MISO operational control. Generally, greater than 100 kV, but includes some 69 kV. Category B includes single generator, transmission circuit and transformer outages. It also includes single pole block of DC lines.
- NERC Category C1, C2, and C4 through C9 faulted events. The more severe events will be studied per the standards. All events to be documented and studied over study cycle. Transmission Owners and MISO staff will document NERC Category C coverage.
- NERC Category C3 by control area including ties. This also includes double generator outages by control area. Selected generator plus branch C3 contingencies.
- NERC Category C from previous MTEP study which resulted in planning criteria violation (or exception) or used to justify upgrade project.
- NERC Category D events. Global automated bus outages to cover D8 and D9. Selected Category D events of other types to provide coverage over study cycle.

R3.3 Granularity of Models:

The MTEP base model includes all transmission system elements rated 100 kV and above. Additionally, the base model includes certain 69 kV elements that have been identified by member Transmission Owners as potentially significant for system reliability studies.

R3.4 Remedial Action Plans:

The MISO base model for evaluating SOLs includes analysis of known Special Protection Systems and Remedial Action Plans.

R3.5 Generation, Load, and Interchange:

All existing generators and future generators with a filed Interconnection Agreement will be modeled. Any additional generation needed to serve future load growth will be modeled based on input from future generation modeling processes described in Section 4.4 of this BPM. New information on generators in the external system through coordinated data exchange with other external entities will also be modeled. Retirement of existing generators will also be updated based on the information available through the System Support Resource study process (see Section 7.2). The load forecast information is based on the stakeholder input in the model building process. This information is reviewed and compared against load flow data from NERC series models, load forecast information as filed with FERC and State regulatory agencies. Interchange and transaction data are also updated via the model building process which will include any new transactions or changes from the Transmission Service Planning process.

R3.6 Criteria for determining when violating an SOL qualifies as an IROL:

In the annual MTEP planning study, thermal overloads greater than 125% of SOL are tested for potential uncontrolled separation, or Cascading Outages. Steady State simulations non-converged contingencies are tested for potential instability in Transient Stability Studies. Additionally, a Voltage Stability Study is performed to determine voltage instabilities at transfer conditions and associated monitored interface flows to identify transfer limits on voltage stability interfaces. Details of these study procedures are documented in section 4.3.7.1 of this BPM.

R4 Issuance of Documentation:

This SOL Methodology, and any change to it, will be issued to the following entities prior to the effectiveness of the change.

R4.1 Adjacent Planning Authority:

Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the SOL Methodology.

R4.2 Reliability Coordinator and Transmission Operator:

Each Reliability Coordinator (MISO) and Transmission Operator that operates any portion of the MISO's Planning Authority Area.

R4.3 Transmission Planner:

Each Transmission Planner that plans a portion of the MISO Planning Authority Area

R5 Documented Response Time:

If a recipient of this SOL Methodology provides documented technical comments on the methodology, the MISO will provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response will indicate whether a change will be made to the SOL Methodology and, if no change will be made, the reasoning behind the decision.

R6 Data Retention Period:

The MISO shall keep all superseded portions of this SOL Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on its SOL Methodology and associated responses for three years.

Appendix M: Critical Facility Identification Procedure

1 Purpose

This procedure provides the methodology the MISO employs to define and determine transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV in its Planning Coordinator Area that are critical to the reliability of the Bulk Electric System (BES), also known as Critical Facilities, for which compliance with the relay loadability requirements of NERC Reliability Standard PRC-023-1 Requirement 1 (and any successor standards thereto) is required to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. This procedure identifies the assessment methodologies and performance criteria used to identify Critical Facilities specific to the planning horizons Transmission Asset Management and Operations each have roles and responsibilities in the identification of facilities critical to the Bulk Electric System.

This procedure applies to the identification of Critical Facilities for use in meeting NERC Reliability Standard PRC-023-1 Requirement 3(and any successor standards thereto) in MISO's role as Planning Coordinator/Planning Authority. MISO shall identify Critical Facilities and shall make the list available to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers and other stakeholders with an identified need and reason for access to the information in a secure manner that protects this information.

This Critical Facilities list has no application to or association with the list of Critical Assets and/or Critical Cyber Assets developed by MISO to comply with NERC Critical Infrastructure Protection ("CIP") Reliability Standards, CIP-002 through CIP-009 (and any successor standards thereto). Identification of a facility on the Critical Facility list has no implication as to whether or not that facility is a Critical Asset and should not be used as a factor for consideration in an entity's Critical Asset risk assessment methodology.

This Critical Facilities list does not apply to those standards that require a functional entity other than MISO to identify critical facilities. For example, FAC-003-1 requires the Regional Reliability Organization (RRO) to identify facilities below 200 kV that are critical. MISO is not a RRO and, thus, this Critical Facility list is not intended to satisfy an obligation to identify to which sub-200kV facilities FAC-003-1 applies.

2 References

NERC Reliability Standards:

2.1 PRC-023-1 Transmission Relay Loadability

MISO:

2.2 Transmission Planning Business Practice Manual BPM 020

2.3 List of Critical Facilities published on the MISO Extranet Site

3 Definitions

Capitalized terms herein shall have the meaning provided in the NERC *Glossary of Terms Used in Reliability Standards* or the MISO Corporate Glossary. In addition, the following terms which have not been defined in the NERC *Glossary of Terms Used in Reliability Standards* shall be defined as follows for the purpose of this document:

Critical Facilities: Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV in the MISO Planning Coordinator Area that are critical to the reliability of the Bulk Electric System and must meet NERC Reliability Standard PRC-023-1 Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability.

4 Roles and Responsibilities

Transmission Asset Management-Expansion Planning will perform MISO Transmission Expansion Plan (MTEP) studies to identify IROLs in accordance with the Transmission Planning Business Practice Manual BPM 020 for the planning horizon and determine which IROLs should be included in the Critical Facilities list.

Operations-Outage Coordination will identify standing operating guides with IROLs and make them available to Operations – Operations Procedures and Compliance (OPC) and will also notify them of any pending IROLs from seasonal assessments. Operations Procedures and Compliance will request Critical Facilities from the Transmission Owners, review standing operating guides for IROLs, and post and manage the list of Critical Facilities.

Transmission Asset Management - Expansion Planning – Expansion Planning shall notify Operations – Outage Coordination of any new IROLs identified in the seasonal assessments.

Operations – Operations Procedures and Compliance (OPC) shall compile lists of Critical Facilities provided by the Transmission Owners, Transmission Expansion Planning, and Operations – Outage Coordination and work with Client Relations to request the Transmission Owners' self-determined list of their Critical Facilities.

Client Relations shall work with Operations – OPC to request the Transmission Owners' self-determined list of their Critical Facilities.

5 Process to determine Critical Facilities

5.1 Transmission Asset Management (TAM) – Expansion Planning – MISO IROL Facility List [In Support of FAC-010 and FAC-014]

Transmission Asset Management – Expansion Planning shall create a list of Critical Facilities based on IROLs identified through the MISO Transmission Expansion Plan (MTEP) process **that require load shed in excess of load shedding limits** defined within the Transmission Planning Business Practice Manual (TPBPM) as mitigation measures to avoid a cascade event on the Bulk Electric System. All monitored and contingent facilities on the Bulk Electric System from the IROLs that impact transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV shall be included in the Critical Facility list. MISO IROLs are consistent with its Methodology document and produced from annual MTEP reliability assessment.

The MISO IROL methodology defines planning horizon IROLs as instabilities including thermal, voltage and angular consistent with the TPL-003 system performance tests and requirements. All Planning Horizon IROLs are therefore mitigated in the MISO MTEP. In the annual MTEP planning study, thermal overloads greater than **125%** of SOL** are tested for potential instability. These are tested for potential cascade by tripping the overloaded branch and checking for subsequent overloads greater than 125% of the SOL.

Additionally, **non-converged contingencies** are tested for potential instability. IROL system conditions and performance together with the mitigations necessary to eliminate them are then reported. Potential IROLs are then identified based on the criteria established in the Transmission Planning Business Practices Manual BPM-020.

**** For pre-contingent conditions, MISO plans to Normal Rating and for post-contingent conditions, MISO plans to Emergency Rating.**

5.2 Member Transmission Owner Roll Up

The MISO shall supplement the list of Critical Facilities identified by Transmission Asset Management pursuant to Section 5.1 above with any additional Critical Facilities identified by the MISO Transmission Owners [NERC-registered Transmission Planners].

Operations –OPC works with Client Relations to semi-annually request and compile a list IROLs and SOLs received from the Transmission Owners. A copy of this list shall be provided to Transmission Asset Management – Expansion Planning for review to determine which facilities should be included in the Critical Facilities list for PRC-023-1.

In order to maintain consistency across the MISO footprint in methodology, MISO staff proposes that MISO Transmission Owners select facilities for inclusion on the list provided to MISO based on consideration of:
Facilities, inadvertent trip of which could result in a demonstrated cascading on the Bulk Electric System as found through the application of NERC TPL standards.

5.3 Input From Adjoining Planning Coordinators and Affected Reliability Coordinators

Transmission Asset Management – Expansion Planning shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators in developing the list of Critical Facilities and shall supplement the list, as appropriate, based on this input.

5.4 Compile and Post List

Transmission Asset Management – Expansion Planning shall compile the list of Critical Facilities from their own review described in sections 5.1 above and supplemented according to sections 5.2 and 5.3. The approved Critical Facilities list will be posted on both the MISO extranet site (access restricted to Reliability Authorities on record with the MISO) and the MISO ftp site (a secured website with limited access). This list is available to the appropriate Reliability Coordinator, Transmission Owners, Generator Owners, and Distribution Providers as required by PRC-023-1 R.3.3. If any change is made to the list of Critical Facilities, a new list shall be posted within 30 days of any such change.

Expansion Planning shall also send a notification to all appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers whenever a new list is posted. The list of Critical Facilities shall be posted in both Excel and PDF format.

Transmission Owners of 100-200 kV class circuits[1] to which the relay loadability standard (PRC-023-1) shall apply, as referenced by MISO Transmission Asset Management - Expansion Planning will also be identified in the published list.

6 Obtaining MISO Agreement with Calculated Circuit Capability

Operations – OPC shall coordinate with Transmission Asset Management – Expansion Planning and Operations – Outage Coordination to review and respond to any requests for agreement from the MISO Planning Coordinator and Reliability Coordinator with the calculated circuit capability used by any Transmission Owner, Generator Owner, or Distribution Provider who chooses to use a circuit capability with practical limitations in accordance with NERC Reliability Standard PRC-023-1 Requirement 2.

7 Disclaimer

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[i] PRC-023-1 R2